8 Regulatory Practices – United States and Foreign

8.1 Scope Statement

"Summarize regulatory practices outside of the United States (i.e., Canada, United Kingdom, Norway, Australia, Russia, Saudi Arabia, and South America)."

In addition to foreign regulatory practice, this scope statement was expanded to include a summary of U.S. standards, regulations, and recommended practice guidelines in the following section. Then the regulatory procedures and guidelines on this subject from different sources can be more readily compared.

8.2 U.S. Codes and Standards Evaluation

8.2.1 49 CFR 192 and 195

49 CFR 192 and 195 are the governing regulations for transportation of gas and hazardous liquids by pipeline and present the minimum federal safety standards that must be met in design and operations of pipeline systems within the United States.

Minimum requirements for the protection of gas lines constructed of metallic pipe from external, internal, and atmospheric corrosion are given in 49 CFR 192, Subpart I. However, SCC is not explicitly covered. Generally, Subpart I requires pipelines to have an external protective coating and a cathodic protection system. Monitoring methods and intervals to verify the proper functioning of the cathodic protection system are also outlined. In addition, remedial measures are discussed for those instances when general or localized pitting corrosion is identified.

49 CFR 195 has similar requirements for protective coatings (§195.238) and cathodic protection systems (§195.242), as well as monitoring and mitigation measures (§195.414, §195.416 and §195.418). Once again, however, SCC is not explicitly discussed.

Both 49 CFR 192 and 195 incorporate numerous publications by reference and the applicable standards are discussed below.

8.2.2 ASME B31.4

The ASME Code for Pressure Piping B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* (B31.4) is the current industry standard for design and operations of liquid pipelines and is used to supplement 49 CFR 195. As with 49 CFR 195, Chapter VIII of B31.4 details minimum requirements and procedures for protection of ferrous pipe from external and internal corrosion; however, it too does not explicitly discuss SCC.

8.2.3 ASME B31.8 and B31.8S

The ASME Code for Pressure Piping B31.8, *Gas Transmission and Distribution Piping Systems* (B31.8), and ASME B31.8S, *Managing System Integrity of Gas Pipelines* (B31.8), are the current industry standards for design and operation of gas pipelines and are used to supplement 49 CFR 192. As with 49 CFR 192, Chapter VI of B31.8 details the minimum requirements and procedures for corrosion control of exposed, buried, and submerged metallic piping. In addition, B31.8 discusses corrosion protection issues related to pipelines in arctic environments and high-temperature service and, of particular interest for this report, briefly discusses environmentally induced and other corrosion-related phenomena, including SCC in Paragraph 866.

However, the statements made are very general in nature and essentially only acknowledge the phenomena and that operators should be aware of the potential for SCC to occur. The knowledge that has been gathered and current research to better understand the phenomena are mentioned and, in the end, B31.8 "suggests that the user refer to the current state of the art."

The supplement to B31.8, B31.8S, outlines an integrity management plans to address SCC in Appendix A3, *Stress Corrosion Cracking Threat*. This plan only addresses "the threat, and methods of integrity assessment and mitigation for high pH type SCC of gas line pipe." It acknowledges that near neutral-pH SCC would require its own plan. The appendix is divided into six sections:

- Scope
- Gathering, Reviewing, and Integrating Data
- Criteria and Risk Assessment
- Integrity Assessment
- Other Data
- Performance Measures

B31.8S, Appendix A3, discusses two inspection and mitigation activities deemed acceptable for addressing pipe segments on which a risk of SCC has been identified through the risk assessment process. These methods are Bell Hole Examination and Evaluation, and Hydrostatic Testing. However, if there is an in-service leak or rupture attributed to SCC, the procedure requires the segment to be hydrostatically tested within 12 months.

In Section 6 of B31.8S the use of ILI for SCC threat assessment is generally discussed, with Section 6.2.2 noting the effectiveness of Ultrasonic Shear Wave Tool and the Transverse Flux Tool. Table 4 presents a number of acceptable threat prevention and repair methods for numerous potential pipeline threats, including SCC.

8.2.4 ASME B31G and RSTRENG

ASME B31G, *Manual for Determining the Remaining Strength of Corroded Pipelines* (B31G), is based on research completed by Battelle Memorial Institute in 1971. This work examined the fracture initiation behavior of metal-loss defects caused by corrosion in line pipe to better understand failure mechanisms associated with these defects. ASME B31G, Section 1.2, *LIMITATIONS*, specifically notes: "This Manual applies only to defects in the body of line pipe which have relatively smooth contours and cause low stress concentrations (e.g. electrolytic or galvanic corrosion, loss of wall thickness due to erosion)." However, these methods can be used to evaluate the remaining strength of a piece of pipe from which stress corrosion cracks were removed by grinding or buffing, leaving a smooth depression in the pipe wall.

Subsequent to the initial Battelle research, the AGA Pipeline Research Committee assumed responsibility for further research and began developing procedures for predicting the pressure strength of line pipe containing various sizes and shapes of corrosion defects.

The main goal of the research was to "examine the fracture initiation behavior of various sizes of corrosion defects by determining the relationship between the size of a defect and the level of internal pressure that would cause a leak or rupture." The procedure is based on a total of 47 full-scale tests on pipe containing actual corrosion defects and was further validated in tests conducted by British Gas.

B31G was later modified to reduce perceived conservatism in the model. A total of 86 burst tests on pipe containing corrosion defects were conducted to validate the Modified B31G method. RSTRENG (Remaining Strength of Corroded Pipe) was developed from the Modified B31G method to allow assessment of a river bottom profile of the corroded area to provide more accurate predictions of remaining strength.

Figure 8-1 presents a comparison of how the three methods determine the area of metal loss associated with a corrosion defect. B31G assumes a parabolic shape for short corrosion (B≤4.0, where B is determined using a formula that is based primarily on the ratio of the depth of the defect to the wall thickness of the pipe) and a rectangular profile for long corrosion. The Modified B31G method (shown as "Simplified RSTRENG" in the figure) assumes a rectangular profile with a depth of 0.85 of the maximum. RSTRENG uses the actual river bottom profile of the defect.

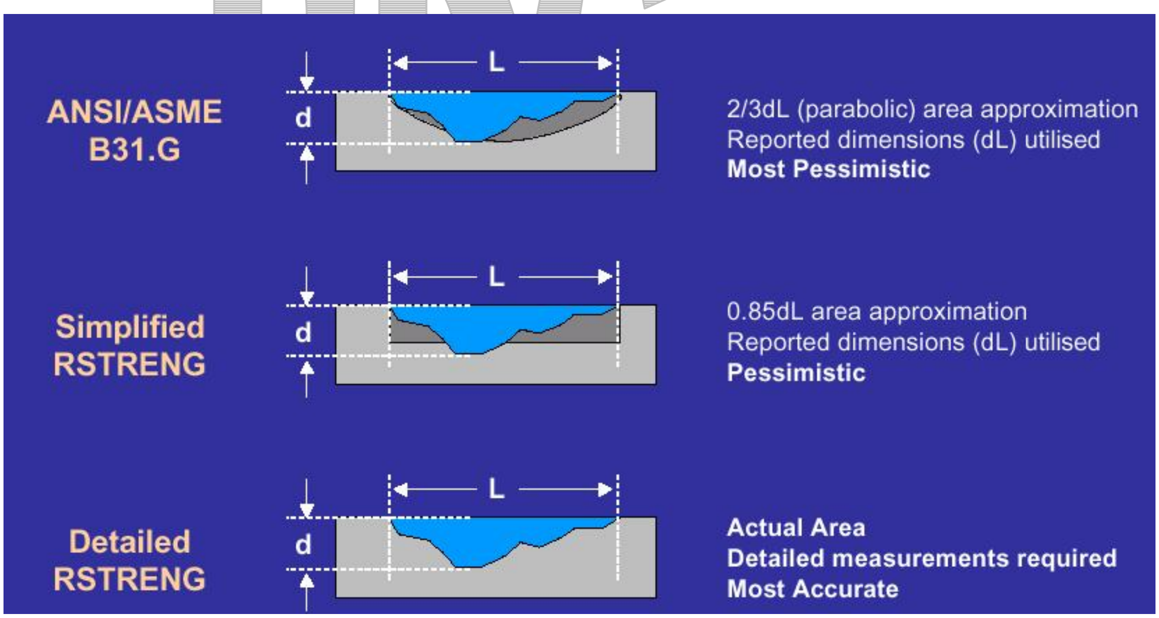

Figure 8-1 Comparison of B31G and Related Methodology

All three methods allow a maximum defect depth of 80 percent of nominal wall thickness and predict failure stress based on an assumed flow stress (1.1 SMYS for B31G and SMYS plus 10 ksi for Modified B31G) and the ratio of area of metal loss to original area with an applied geometry correction factor (Folias Bulging Factor). A defect is considered acceptable if the predicted failure stress level is greater than or equal to SMYS.

Figure 8-2 presents a general description of the acceptable application of these methods. The figure schematically shows the progression of defects with size: from "cracks," then to "grooves" then to "general or areal corrosion." ("Holes" are generally characterized with small equal dimensions in both the circumferential and axial direction, progressing to "pitting" and once again to general or areal corrosion). As shown, B31G and its variations are valid for evaluation of general and areal corrosion, pitting and wall thinning, and <u>*not*</u> cracks, grooves, or holes including SCC. Thus, these methods are <u>*not*</u> applicable for the evaluation of SCC. However, as stated above, these methods can be used to evaluate the remaining strength of a piece of pipe from which stress corrosion cracks were removed by grinding or buffing, leaving a smooth depression in the pipe wall.

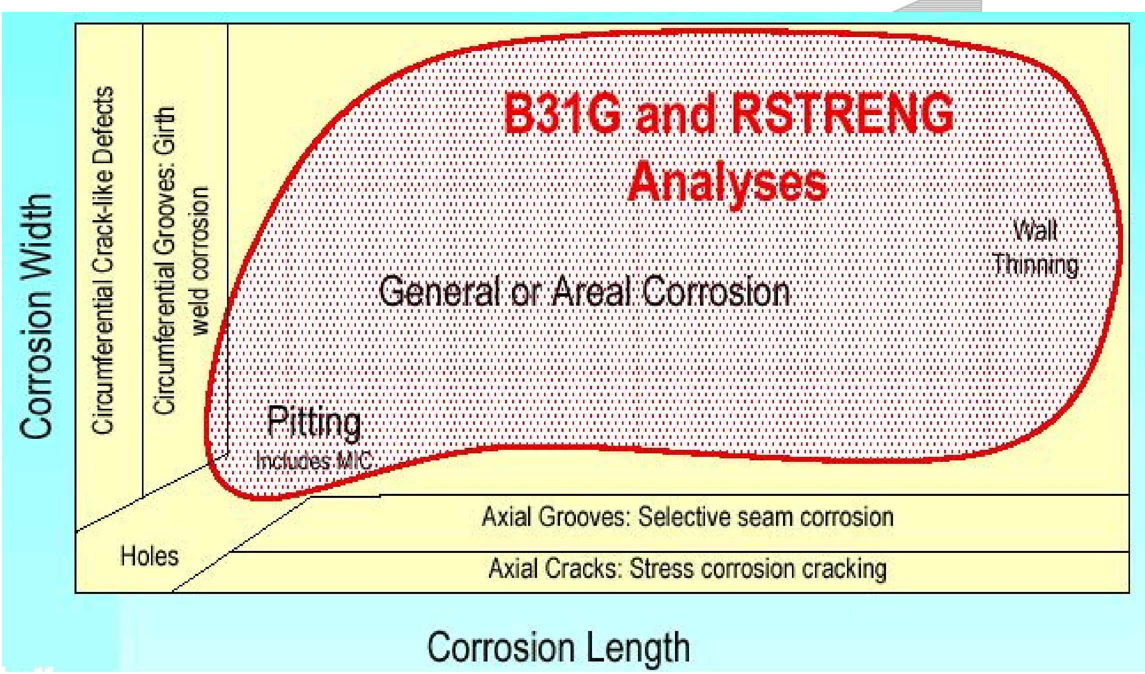

Figure 8-2 Applications Area of B31G and RSTRENG (Battelle)

8.2.5 API RP579

API Recommended Practice 579 (RP579), *Fitness-For-Service*, "provides guidance for conducting Fitness-For-Service (FFS) assessments using methodologies specifically prepared for equipment in the refining and petrochemical industry." FFS assessments are "quantitative engineering assessments which are performed to demonstrate the structural integrity of an in-service component containing a flaw or damage." RP579 is written specifically for ASME and API codes other than B31.4 and B31.8. However, application to pressure containing equipment constructed to other codes is discussed, though the referenced appendix for the primary method is still in development.

Several sections of RP579 are applicable to assessment of flaws or damages of in-service pipelines. In particular, Sections 4, 5, and 6 cover the procedures for assessment of general and local metal loss resulting from corrosion/erosion, mechanical damage, or pitting corrosion. These assessments are geared towards re-rating a line by identifying an acceptable reduced maximum allowable working pressure (MAWP) and/or coincident temperature. Use of these procedures is applicable in cases where "the original design criteria were in accordance with a recognized code or standard."

Section 9 provides guidance on assessment of crack-like flaws that include "branch type cracks associated with environmental cracking" such as SCC. The procedures presented can be applied to SCC "provided a predominant crack whose behavior largely controls the structural response…can be identified." Three levels of assessment procedures are presented.

A Level 1 assessment follows a series of basic steps and does not take into consideration the pipeline material fracture toughness (a measure of its ability to resist failure by the onset of a crack extension to fracture). Therefore, a Level 1 assessment typically results in a conservative solution. It is also limited to the assessment of materials with SMYS lower than 40 ksi.

Level 2 assessments follow a more rigorous procedure based on more detailed material properties, including material toughness, to produce a more exact solution. Level 2 assessments also account for stress distributions near the cracked region including residual stresses (categorized as secondary stresses) from welding. If actual steel yield strengths are available for the pipeline being assessed, the calculations for residual stresses take this into account. However, if only the minimum yield strength is available, an acceptable alternate method for calculating the residual stresses is provided.

Both Level 1 and Level 2 assessments assume that the crack-like flaw is subject to loading conditions and/or an environment that will not result in crack growth. Therefore, Level 1 or 2 assessments can only be used to evaluate SCC if the operator can prove that the SCC colony has become dormant.

The Level 3 assessment provides the best estimate of structural integrity and is the assessment level that is required if sub-critical crack growth is possible. In cases where sub-critical crack growth is possible, a remaining life assessment is also required, along with crack growth monitoring, either in-service or at a shutdown inspection.

8.2.6 Other Failure Criteria Methods

There are a number of techniques available by which to assess failure criteria for crack-like defects in pipelines. All these techniques predict the relationship between critical defect size and failure pressure. Probably the best-known and most widely utilized method is the AGA NG-18 ln-secant formula. However, other techniques, such as the Pipe Axial Flaw Failure Criterion (PAFFC), the Level 2 Strip Yield Model, and the CorLAS™ model, are also available. Each of these methods is mentioned in *Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* (NEB 1996), and described in further detail in the following sections.

8.2.6.1 NG-18 ln-secant Formula

In the early 1970s, Battelle developed an assessment methodology for analyzing axial flaws in pipelines based on an extensive series of burst tests. The Battelle method, or ln-secant criterion, was based on a strip-yield model and empirically derived for surface axial flaws and is given as:

$$\frac{C_V \pi E}{4 A_C L_e \sigma_f^2} = \ln\left[\sec\left(\frac{\pi M_S \sigma_H}{2\sigma_f}\right)\right]$$ **Equation 8.1**

where:

E is the elastic modulus,

L_e is an effective flaw length equal to the total flaw length multiplied by $\pi/4$ for a semi-elliptical flaw shape common in fatigue,

σ_f is the flow stress typically taken as the yield strength plus 10 ksi or else as the average of yield and ultimate tensile strengths,

σ_H is nominal hoop stress due to internal pressure,

C_V is the upper shelf Charpy V-Notched impact toughness,

A_c is the cross-sectional area of the Charpy impact specimen. (Note that a constant for compatibility of units between C_V and A_c may be necessary.)

The term M_S is a stress magnification factor for a surface-breaking axial flaw, calculated as:

$$M_S = \frac{1-(a/t)(M_T)^{-1}}{1-a/t}$$ **Equation 8.2**

where

a is flaw depth, and

t is the pipe wall thickness.

The term M_T is Folias' original bulging factor for a through-wall axial flaw, written as:

$$M_T = \sqrt{1+1.255\left(\frac{L_e^2}{2Dt}\right)-0.0135\left(\frac{L_e^4}{4D^2t^2}\right)}\text{, for }\left(\frac{L_e^2}{Dt}\right)\le 50$$ **Equation 8.3a**

or

$$M_T = 0.032\left(\frac{L_e^2}{Dt}\right)+3.3\text{, for }\left(\frac{L_e^2}{Dt}\right)>50$$ **Equation 8.3b**

This method only applies to flaws that existed in the pipe prior to pressurization and does not consider possible growth due to the effects of pressure, either in-service or hydrostatic testing.

In addition, in a study conducted by Battelle for TransCanada Pipe Lines (TCPL), it was concluded that the ln-secant criterion is not appropriate for assessing pipeline failure pressures for lines containing SCC, such as has occurred on the TCPL system. The overly conservative predictions of failure pressure were attributed primarily to the effect of multiple cracking that is associated with SCC, as compared to the single rectangular axial flaw assumed in deriving the ln-secant criterion. The study also identified the empirical calibration of the criterion as contributing to the observed conservatism and inconsistency. "In another study conducted by Battelle for TCPL, the results suggest that the presence of multiple cracks effectively reduces the crack driving force below that for a single crack. Therefore, failure criteria based on a single crack will tend to underestimate failure pressures where multiple cracks are present." (NEB 1996)

8.2.6.2 Pipe Axial Flaw Failure Criterion

The ln-secant criterion: "…was based on flaw sizes that existed prior to depressurization and did not address possible growth due to pressure in service or in a hydrostatic test or during the hold time in a hydrotest…However, with the advent of newer steels and the related increased toughness that supported significant stable flaw growth, it became evident that this criterion should be updated." (Leis and Ghadiali 1994). This updating resulted in the development of the PRCI ductile flaw growth model "…which specifically accounted for the stable growth observed at flaws controlled by the steel's toughness and a limit-states analysis that addressed plastic-collapse at the flaw." Due to the increased complexity (when compared to the ln-secant formula) of this model, which made it difficult for day-to-day use, a computer program was developed to enhance the usability of the method. This program was titled Pipe Axial Flaw Failure Criterion or PAFFC and is available for download from the PRCI Web site.

PAFFC can be used to determine the effect of a single external axial flaw on the failure pressure in a pipeline, given the pipe diameter and wall thickness, yield and ultimate (flow) stress, and upper shelf Charpy V-notch toughness.

8.2.6.3 Level 2 Strip Yield Model

The Level 2 Strip Yield Model is a collapse-modified strip yield model for axial surface cracks in line pipe developed at CANMET in the early 1990s. The model is an alteration of the approaches in the British R6 (a detailed single failure curve analysis) approach, and the somewhat similar PD6943 approach. Note that PD6943 has been superceded by PD7910.

"Briefly, the model interpolates between a brittle fracture limit, (dependent on the stress intensity factor), and a collapse limit, (dependent on the flaw size and flow stress)…The approach follows the basic premise of a strip yield model, where failure occurs for K_r and S_r on the 'failure curve.' K_r is the ratio of the applied (elastic) crack driving force to the material toughness and measures the proximity to fracture, and S_r is the ratio of the applied net section stress to the flow stress and measures the proximity to plastic collapse…The overall approach has been validated against the results from the original Battelle work, and is applicable for oil and gas pipelines with an $R/t \geq 20$." (CEPA 1997)

8.2.6.4 CorLAS™

The general approach used for engineering critical assessment (ECA) of crack-like flaws using CorLAS™ is illustrated in Figure 8-3. The first step is characterization of the initial flaw type and size. This includes determining if the flaw is crack-like. Next, the critical or final flaw size at failure under operating or upset conditions is predicted. Remaining life is computed based on growth from the initial to the final flaw size. If the final flaw size is not greater than the initial one, no remaining life is predicted. If the flaw growth rate cannot be estimated, remaining life cannot be predicted, and monitoring is recommended to assure safe pipeline operation.

The size of the flaw is characterized by means of in-service inspection or hydrostatic pressure testing. In-service inspection may yield a detailed profile or contour of the flaw depth as a function of its length or only the flaw length and depth. When a detailed flaw depth profile is available, an effective surface flaw is determined from this profile using the procedures described in detail by Kiefner and Vieth (Kiefner and Vieth 1993). The effective flaw area is defined by its effective length and actual cross-sectional depth. The effective flaw depth is then defined based on a semi-elliptical flaw shape and equivalent flaw area.

When a detailed flaw profile is not available, the effective flaw is characterized as having a semi-elliptical shape with the maximum measured depth and length. When hydrostatic pressure testing is used to characterize the surface flaw, the effective flaw size is estimated to be the largest flaw that would have survived the test. In practice, these effective flaw sizes are estimated as a function of L/d (flaw length/flaw depth), because this ratio affects the critical flaw depth.

It must be determined if the flaw is crack-like. Inspection data usually provide this information. If the inspection cannot clearly identify the flaw type, it is conservative to assume a crack-like flaw of the measured size for ECA. However, when hydrostatic testing is employed, the flaw type must be inferred from other data. If this cannot be done with confidence, then a non-crack-like flaw should be used for computing the initial size from the hydrostatic testing data and a crack-like flaw should be used to predict failure conditions to yield a conservative ECA.

The critical flaw size is computed for two different failure criteria: flow strength and J_c. J_c is an elastic plastic fracture mechanics parameter and is used because typical pipeline steels are quite ductile and tough. Both flow strength and fracture toughness must be considered as possible failure criteria for crack-like flaws. The smaller of the two calculated critical flaw sizes is the one predicted to result in failure. Remaining life is the time required for the flaw to grow from its initial to final size. It is computed by integrating a flaw-growth relationship from the initial to final flaw size.

The critical flaw size for the flow-strength failure criterion is determined by solving the following equation for A (effective flaw area):

$$\sigma_f = S_{fl} \cdot RSF = S_{fl} \cdot \left(\frac{1 - A/A_o}{1 - A/(M \cdot A_o)} \right) \qquad \textbf{Equation 8.4}$$

where:

σ_f is the applied nominal stress at failure,

S_{fl} is the material flow strength,

A_o is the flaw length times wall thickness, and

M is the Folias (bulging) factor.

Values of M are computed using the relationship given by Kiefner and Vieth (Kiefner and Vieth 1993). For a specific relation among A, L, and d, such as a semi-elliptical shape with a constant L/d, L and d are uniquely defined by the value of A obtained from solving Equation 8.4. Because M is a function of L, Equation 8.4 is solved iteratively. The value of S_{fl} is determined from *TYS* (Tensile Yield Strength) or from a combination of *TYS* and *TUS* (Tensile Ultimate Strength) using one of the following two expressions:

$S_{fl} = TYS + 10$ ksi (68.95 Mpa) **Equation 8.5a**

$S_{fl} = TYS + C_{fl}\,(TUS - TYS)$ **Equation 8.5b**

C_{fl} is a constant between 0 and 1.0 and is usually taken to be 0.5. Equation 8.5a is based on burst tests of steel pipe specimens (Kiefner, et al 1973), while Equation 8.5b with $C_{fl} = 0.5$ is usually used in plastic collapse analysis.

The following formulation for a semi-elliptical surface flaw is used to compute values of applied J as a function of a (flaw size) and stress, σ:

$$J = Q_f \cdot F_{sf} \cdot a \cdot \left(\frac{\sigma^2 \cdot \pi}{E} + f_3(n) \varepsilon_p \sigma \right)$$ **Equation 8.6**

where:

Q_f is the elliptical flaw shape factor,

F_{sf} is the free-surface factor,

a is the flaw depth,

σ is the stress,

E is the elastic modulus,

n is the strain hardening exponent, and

ε_p is the plastic strain.

The function $f_3(n)$ in Equation 8.6 is from stress analyses performed by Shih and Hutchinson (Shih and Hutchinson 1975). A power law with the exponent n characterizes σ as a function of ε_p. Values of *TYS* and n are used to determine the power law coefficient.

Several improvements have been made to the CorLAS™ model since the original development. Tearing instability was added to the fracture toughness failure criteria, formulations for computing values of the J integral for surface cracks were improved, interaction criteria were developed for co-planar flaws, and relationships for estimating values of the strain-hardening exponent were developed.

In the original model, described above, fracture was predicted to occur when applied J reached J_c. For tough pipeline steels, this approach is conservative because a significant amount of stable crack tearing occurs before fracture instability is reached. For this reason, the tearing instability criterion of Paris, et al. (1979) was incorporated into the failure model.

Tearing instability is predicted to occur when applied T (crack tearing parameter) equals or exceeds T_{mat} (tearing modulus) of the pipeline steel. T_{mat} is defined by the following equation:

$$T_{mat} = {}^{dJ}\!/_{da} \cdot {}^{E}\!/_{\sigma_{fl}^{\,2}}$$ **Equation 8.7**

T_{mat} is determined from a standard laboratory fracture toughness test. The applied ${}^{dJ}\!/_{da}$ is a function of applied load, pipeline configuration, crack size, and crack shape and is determined by stress analysis. Applied T is calculated in the same manner as T_{mat} is calculated in Equation 8.7.

Descriptions of the other improvements are summarized in a recent IPC paper (Jaske and Beavers 2002)

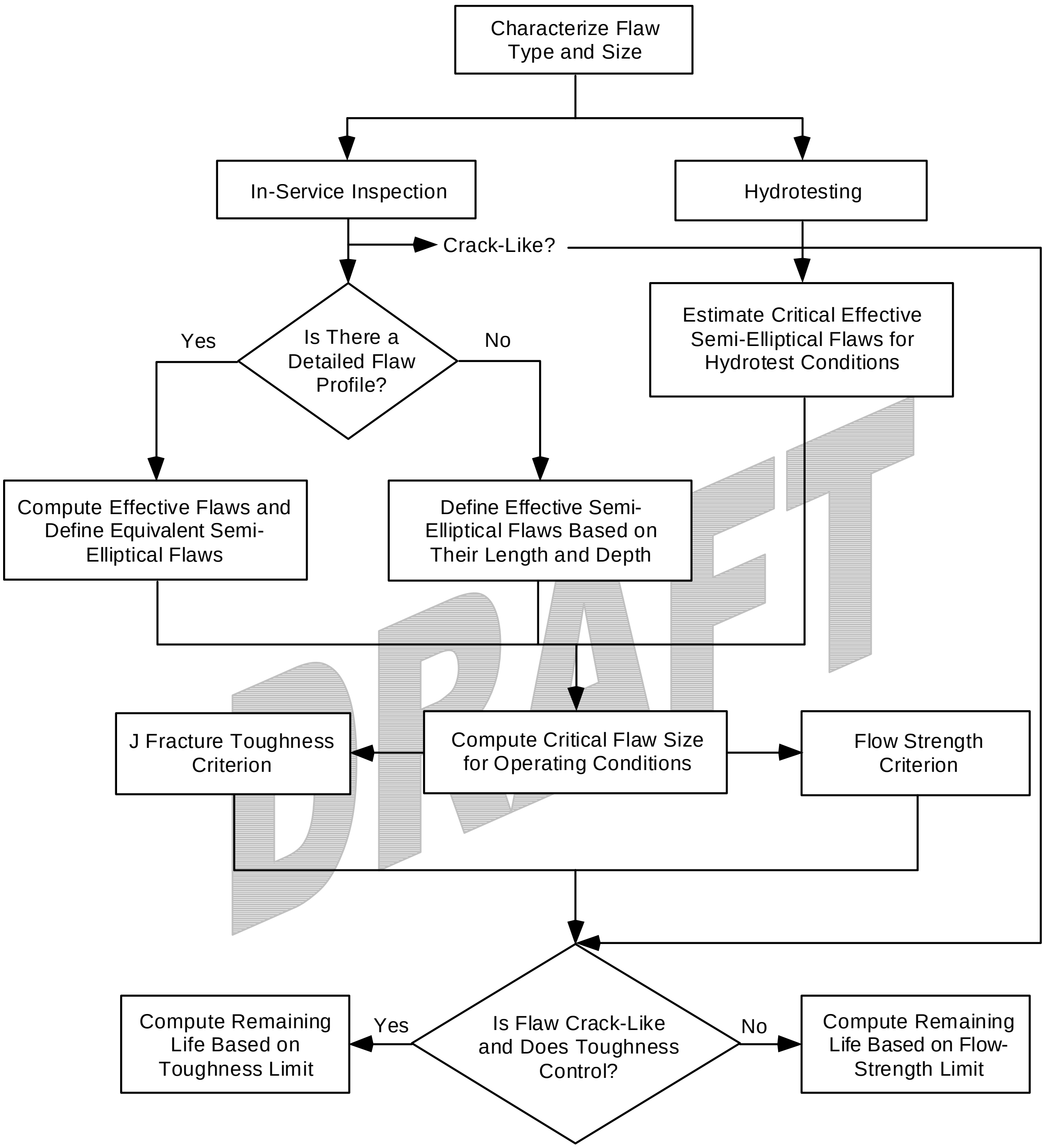

Figure 8-3 General Approach for Engineering Critical Assessment (ECA) of Crack-Like Flaws in Pipelines Using CorLAS™

8.2.6.5 Application

The application of these failure criteria results in curves showing critical flaw depth versus length for a given pressure. An example is shown in Figure 8-4. Normally, curves generated for MOP and the maximum hydrostatic test pressure are compared to determine the amount of growth in depth that is necessary for a defect to fail in service. Unless data are available to support an assumption of a specific critical crack length, the minimum value of growth in depth that is necessary for a defect to fail in service should be used as a conservative value for determining a safe retest interval. Usually the assumption of a crack with infinite length results in a conservative estimate of allowable growth in depth.

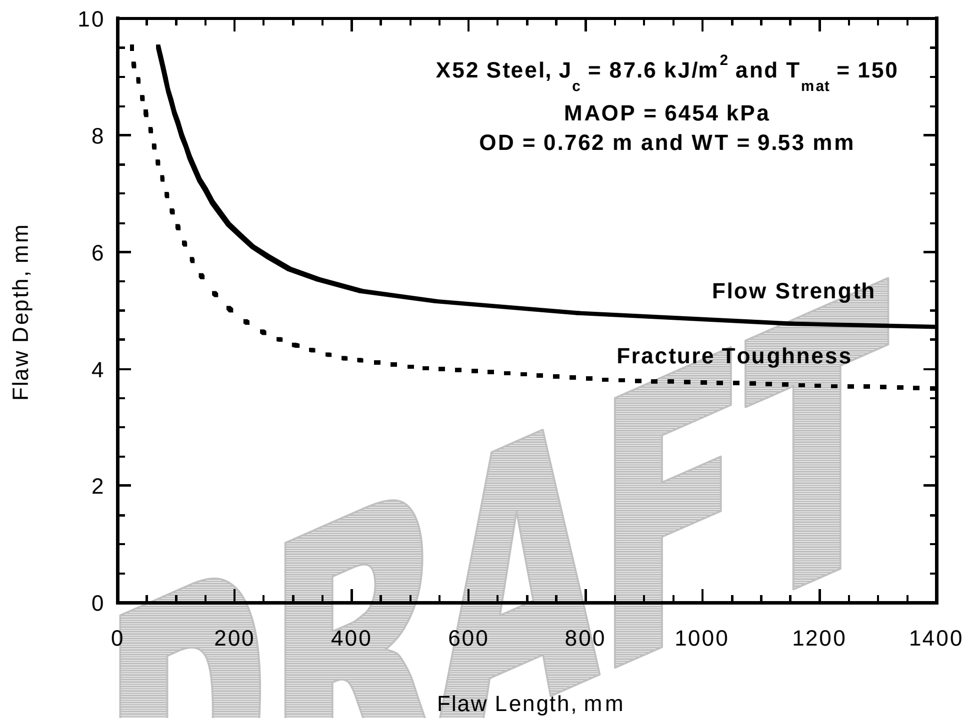

Figure 8-4 Example of Calculated Critical Flaw Depth as a Function of Length Using CorLAS™

8.2.6.6 Comparison

Each failure criterion described above is developed on the basis of certain assumptions and generally has a limited range of applicability. The predictive capability of a failure criterion improves if the specific situation under consideration is consistent with those assumptions and is within that range of applicability.

A comparison of a series of evaluations using each of the four methods described above performed by CEPA was reported in the NEB report, *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* (NEB 1996). This comparison indicated that the ln-secant formula and the Level 2 Strip Yield Model could be very conservative, with significant variances in the level of conservatism, though, unlike the ln-secant formula, the Level 2 Strip Yield Model was not consistently conservative. On the other hand, the predictability for both the PAFFC and CorLAS™ criteria was shown to be much better, with CorLAS™ being the more accurate of the two.

The failure predictions for CorLAS™ are shown as solid circles in Figure 8-5, where the predicted failure stress is plotted as a function of the actual failure stress and the 45-degree dashed line indicates an exact correlation between the two values. Both stresses are given as a percentage of the specified minimum yield strength (SMYS) of the pipe steel. The predictions were made using an effective flaw characterized by only the maximum flaw size (depth and length). Except for one case, the predicted failure stresses were very close to the actual failure stresses. Examination of the data for that case revealed that the SCC flaw was much deeper at its central portion than near its ends, so its effective size was not well characterized by the maximum flaw size. The predicted failure stress was very close to the actual failure stress when the actual flaw-depth profile was used to characterize its effective size, as indicated by the open circle in Figure 8-5.

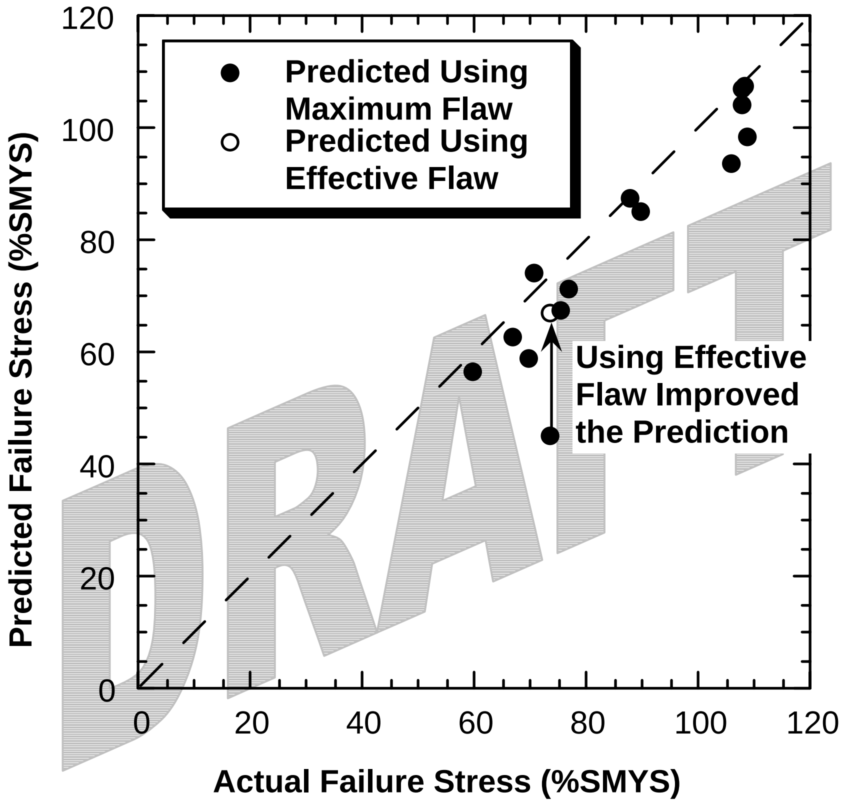

Figure 8-5 Predictions of Failure Stress for Field Failures

8.2.7 NACE International

8.2.7.1 Publication 35103 – External Stress Corrosion Cracking of Underground Pipelines

This report provides a good overview of the SCC phenomenon and how various factors (metallurgical, environmental and stress related) affect the initiation and growth of SCC on pipelines. It also briefly discusses prevention, detection and mitigation. However, as this document was a technical committee report, and not a recommended practice, recommendations and/or guidelines for use by pipeline operators in developing and maintaining an SCC integrity management plan was outside the focus of the report.

8.2.7.2 RP – SCC Direct Assessment (DA)

This recommended practice is currently being developed and will provide a direct assessment procedure for determining whether a pipeline is susceptible to SCC. The general procedure is essentially the same as that given in B31.8S, Appendix A3; however, additional details, including an expanded discussion of near neutral-pH SCC, are presented. A pipeline is considered susceptible to SCC if all of the criteria for either form of SCC in Table 8.1 are met.

As presented by Dr. J.A. Beavers at the OPS SCC Workshop in Houston, Texas, December 3, 2003, the program consists of a four-step process: pre-assessment, indirect inspections, direct examinations and post-assessment. The pre-assessment and indirect inspections steps entail gathering, reviewing and integrating applicable data on pipe materials and coatings, and operating conditions, and then performing a risk assessment. The risk assessment consists of comparing the data to the appropriate criteria.

Table 8.1 Direct Assessment Criteria

Description	Criteria
High-pH SCC	
Age of Pipe	>10 years
Operating Stress	>60%of SMYS
Operating Temperature	>100ºF
Distance from Compressor Station	<20 miles
Coating Systems	All but FBE
Near neutral-pH SCC	
Age of Pipe	>10 years
Operating Stress	>60%of SMYS
Distance from Compressor Station	<20 miles
Coating Systems	All but FBE

Step 3 entails performing direct examinations (i.e., field digs) to validate the results of the risk assessment. Step 4 then evaluates the results of the risk assessment and the direct examinations to determine whether a mitigation plan is required, determine appropriate reassessment intervals, and validate the effectiveness of the SCCDA method.

Further discussion is presented in Chapter 6.3.

8.2.8 Summary of U.S. Codes and Standards

While research papers, reports and other documentation regarding SCC are voluminous, the majority of current U.S. codes and standards are largely silent on the subject. RP579 provides detailed procedures for evaluating a system once SCC has been identified; however, as stated above, the procedures are not specifically applicable to systems designed and constructed to B31.4 or B31.8, and the referenced validation discussion is not yet available. Similarly, the NACE SCCDA recommended practice is not yet available, and even when it is published, may not have the level of detail needed by many operators to implement an effective SCC integrity program.

8.3 Canadian Regulations and Standards

8.3.1 National Energy Board

The NEB regulates approximately 10% of Canadian lines – approximately 45,000 km of intra provincial /cross border pipelines. Such groups as the Alberta Energy and Utilities Board (EUB) regulate intraprovincial lines. The NEB employs approximately 300 personnel, 70 of which are in the pipeline operations business unit. Unlike the U.S., corrosion and SCC rank ahead of 3rd party pipeline incidents on NEB regulated pipelines. (There are a few provincial jurisdictions, notably Ontario, where recent line strikes have disturbed the trend, but by and large throughout Canada corrosion and SCC-related failures dominate.)

According to the Canadian National Energy Board, the occurrence of SCC on Canadian pipelines is a serious matter. Concern about SCC on the Trans Canada Pipeline (TCPL) system led the Board to conduct an earlier inquiry in 1993. From that inquiry, the Board concluded that the SCC situation was being managed appropriately by the affected pipeline companies, considering the extent of the problem as then recognized. However, there were two more major ruptures and fires on the TCPL system in February and July 1995, the last one at a location where it was not believed that SCC could occur. These two pipeline failures, together with further evidence of the more widespread nature of SCC and awareness that research was producing new insights into SCC, led the Board to initiate an Inquiry in August 1995 and the *Report of the Inquiry* [on] *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* (NEB 1996) mentioned in Chapter 3.

An interview at the NEB offices in July of 2004 was conducted to provide an update to the published results of the inquiry. The remainder of this section's remarks are based on that interview.

The CEPA Recommended Practice (RP) (CEPA 1997) satisfied the Board's findings that the industry produce a documented approach to SCC. The Board neither approves nor disapproves technical detail in the approach. There is currently no comparable detail in the CSA (Z662) concerning SCC. It is expected that the CEPA RP document will be updated, but no firm date has been established. Operators are required to report significant SCC as defined in the CEPA RP. The NEB noted that after the first incidents and this RP, they have been informed of a number of investigative digs with one operator reportedly performing over 90 corrosion-related digs per year arising from in-line inspections. Thus, SCC continues to be a serious consideration and an object of continuing oversight and research. A number of personnel and companies (e.g. University of Calgary, CANMET) were mentioned in this regard.

NEB personnel noted that it is sometimes difficult to separate SCC from general corrosion. Since the NEB SCC hearings, only one SCC incident has occurred on NEB regulated lines. They also speculated that one reason for the difference in causes of corrosion/SCC incidents may be the preponderance of tight Canadian lines (e.g. running closer to pipe design limits) when compared to U.S. lines.

The NEB noted that soil models are a good place to start an operator's consideration of SCC. Although this approach must be updated through experience, such a model generally supplies the oversight framework to begin consideration of SCC. FBE has proved, to date, to be an effective coating to prevent SCC. If there is any concern, it might be at weld joints, especially for larger diameter lines.

The NEB follows ILI advancements and looks forward to a tool for crack detection in gas lines, which has a high degree of confidence and repeatability. Ultrasonic tools can be used for SCC detection in liquid lines and appear acceptable although, due to the need for liquid coupling, the methodology is more difficult to implement for gas lines.

Generally, SCC analysis and oversight are approached on a site-specific basis. No generally accepted procedure of defining what level of reduction in factor of safety (FS) from the original FS is established.

Regarding the response to SCC incidents, the Transportation Safety Board (TSB) has the responsibility of incident investigation, while the NEB has the responsibility for return-to-service plans. This is analogous to the roles of the NTSB and OPS in the U.S. Actually, an NEB inspector would typically also be at the site when the TSB is there to facilitate the eventual handover of responsibility. The operator will typically take the lead in public contact, repair plans, and return-to-service plans. Regulatory leadership is provided when the operator's plans fail to meet regulatory requirements and/or expectations.

8.3.2 CSA

The National Standards System (NSS) is the system for developing, promoting and implementing standards in Canada. The Standards Council of Canada coordinates the NSS. The Standards Council of Canada is a Federal crown corporation comprising representatives from the federal and provincial governments, as well as from a wide range of public and private interests. It prescribes policies and procedures for developing National Standards of Canada, coordinates Canada's participation in the international standards system, and accredits more than 250 organizations involved in standards development, product or service certification, testing and management systems registration activities in Canada.

There are four accredited standards development organizations (SDOs) in Canada: the Canadian Standards Association (CSA), the Underwriters' Laboratories of Canada (ULC), the Canadian General Standards Board, and the Bureau de normalisation du Québec. Each SDO develops standards according to the procedures stipulated by the Standards Council of Canada, including the use of a multi-stakeholder committee, consensus-based decision making, and public notice and comment requirements. SDOs may submit standards they develop to the Standards Council of Canada to be recognized as National Standards of Canada. SDOs also develop other standards-related documents, such as codes and guidelines (non-mandatory guidance and information documents). CSA develops standards for pipelines.

In effect since 1994, the current edition of CSA standard CAN/CSA-Z662-99, *Oil and Gas Pipeline Systems Standard*, Section 10.8.2, Evaluation and Treatment of Localized External Corrosion Pitting on Pipe, permits localized corrosion pits to 80 percent of the nominal wall thickness of the pipe, provided that the calculated maximum permissible length of the corrosion is not exceeded. The standard has the same corrosion limits as those specified in previous editions of CSA standards for oil pipelines, most notably standard CAN/CSA-Z183-M86, in effect from 1986 to 1990, and standard CAN/CSA-Z183-M90, in effect from 1990 to 1994.

8.4 Australian Regulations and Standards

In Australia, most standards are published by Standards Australia. Standards Australia is the trading name of Standards Australia International Limited. Standards Australia is an independent, non-government organization. However, through a Memorandum of Understanding, Standards Australia is recognized by the Commonwealth Government as the main non-government standards body in Australia. It is Australia's representative on the International Organization for Standardization (ISO), the International Electrotechnical Commission (IEC), and the Pacific Area Standards Congress (PASC). Standards applicable to pipelines include:

- AS 2885.1 Pipelines – Gas and Liquid Petroleum – Design and Construction
- AS 2885.2 Pipelines – Gas and Liquid Petroleum – Welding
- AS 2885.3 Pipelines – Gas and Liquid Petroleum – Operations and Maintenance
- AS 2885.4 Pipelines – Gas and Liquid Petroleum – Offshore Submarine Pipeline Systems
- AS 2885.5 Pipelines – Gas and Liquid Petroleum – Field Pressure Testing

8.4.1 AS 2885.1 Design and Construction

AS 2885.1, Appendix G, Section G4 "Environmental Related Cracking" gives a brief listing on factors influencing the propensity for high-pH and near neutral-pH SCC. Appendix H, also titled "Environmental Related Cracking," gives a more informative description of SCC, including a brief description of the factors listed in Section G4. Appendix A also gives a brief discussion of the conditions necessary for susceptibility of pipeline steel.

8.4.2 AS 2885.3 Operations and Maintenance

AS 2885.3 in Chapter 5, "Pipeline Structural Integrity," Section 5.2, "Operating and Design Conditions," states four base conditions that the operating authority must ensure. It is noteworthy that the fourth condition is:

> "d) ensure that operating conditions are such that the likelihood of stress corrosion cracking initiation or growth is minimized."

Again, in Section 5.3, "Pipeline Inspection and Assessment," four items are specified to be included in the inspection program with the fourth condition:

> "d) Inspections of any sections on the pipeline identified in the ongoing risk assessment as being of higher propensity for development of stress corrosion cracking."

There is no specific methodology or determination for SCC in this standard aside from these references.

Section 5.4.2.2, “Safety Precautions,” discusses measures to be taken when work is carried out on a corroded pipeline. The first sentence notes: “The operating pressure shall either not exceed the pressure at which the corroded portion was subjected at the time of identification, or it should be reduced to a safe level (initially 80 percent of normal operating pressure).”

8.4.3 APIA

The Australian Pipeline Industry Association (APIA) has ongoing research, including a number of position papers that may be reflected in future AS 2885 editions. AS 2885.1, Issue Number 6.1, Stress Corrosion Cracking (APIA 2003), addresses the implications of a proposed change in design factor from 0.72 to 0.80 with regards to SCC. It is acknowledged that SCC is found on some Australian pipelines, which has resulted in pipeline failures in the past. The Issue paper reviews some of the effects of conditions (e.g., temperature) on SCC.

The paper concludes: “Operating a pipeline with a stress level higher than 72 percent of SMYS can be expected to increase the frequency of occurrence of SCC if other factors relating to SCC remain unchanged.” However, the author notes that it can be controlled by compensating measures and concludes that no substantial change to the Standard is necessary.

8.5 European Regulations and Standards

The European Pipeline Research Group (EPRG) is a leader in investigating SCC, often cited as working in conjunction with PRCI. An example of the reports produced by EPRG is one that deals with the research of a standardized methodology for laboratory evaluation of near neutral-pH SCC. The two major objectives of the report are: 1) to identify the areas with the highest risk of near neutral-pH SCC on existing pipelines so that appropriate measures can be taken: and 2) to produce guidelines for pipe materials, coating, environment and operating service to reduce the risk of near neutral-pH SCC on future pipelines. It is noted that one major obstacle to effective progress in research is the difficulty to reproduce, in a consistent and reliable way, the cracking pattern and the mechanism actually observed in the field experience.

Another research project was launched in late 1996 under the supervision of EPRG Corrosion Committee involving four laboratories (British Gas R&D, British Steel Swinden Lab, Saltzgitter [former Preussag Stahl] and CSM) with a first phase scope of defining and developing a standardized experimental methodology to obtain reliable data for crack initiation and propagation.

8.6 Other Regulations, Standards and Practices

An operator in Saudi Arabia reports that there have been multiple occurrences of external SCC over the years, with the first occurrence going back to the late 1970s. All the occurrences have been associated with disbonded tape-wrap and associated CP in subka areas (subka is an area with a high water table that from the surface looks dry, but where brine is encountered within approximately one foot of the surface). When the tape wrap falls away from the pipe, an alkaline environment is encountered next to the pipe, and external SCC occurs. The operator reports that he no longer uses tape-wrap (since early 1980s) on any new pipelines and instead specifies FBE external coatings. The operator knows of no FBE-coated pipelines that have experienced external SCC. His recommendation for best practice in Saudi is to avoid pipeline burial in subka areas, placing the pipe above ground or in a berm, and to use FBE coating and CP.

The International Science and Technology Center (ISTC) was established by international agreement in November 1992 as a forum for scientists from Russia and the Commonwealth of Independent States. One of their research abstracts states:

> "All countries dealing with exploration of gas and oil face serious problems associated with stress corrosion cracking (SCC) in gas and oil pipelines, which becomes often a cause of fires, explosions and even of death of people. SCC-related failures lead also to great economical and ecological losses. There is a tendency for increase of the number of accidents on main pipelines because of natural aging of the latter. In Russia, Canada, USA and countries of the European Community, such accidents are reported mostly frequent.
>
> Stress corrosion cracking of pipelines was first detected 30 years ago. But until now, in spite of intensive investigations being carried out in this field, mechanisms of stress corrosion cracking and cause accountable for its development in pipe steel remain poorly studied. This concerns first of all a complex character of the process of stress corrosion, in which a variety of factors interact. It is known now that SCC initiates as a result of the interaction of three conditions:
>
> – cyclic tensile stress;
>
> – metallurgic inherited heterogeneity of pipe steel;
>
> – corrosiveness of the pipe environment.
>
> Analysis of mechanisms of stress corrosion made by us in the framework of Project #1344-D (ISTC) has shown a possibility of the involvement of a great variety of microorganisms in initiation and development of cracks in pipe steel. Evidences in favor of our observations were found in papers on microbial corrosion in metal and alloys. Moreover, there are a number of latest papers describing a possibility of direct participation of some microorganisms in such a specific mechanism of corrosion as hydrogen embrittlement."

8.7 References

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